**RES COALITION EX. 3.0**

**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

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| **CENTRAL ILLINOIS PUBLIC SERVICE COMPANY**<br>**d/b/a AmerenCIPS and**<br>**UNION ELECTRIC COMPANY**<br>**d/b/a AmerenUE**<br>**Petition for approval of tariff sheets implementing revised Market Value Index methodology.** | ) | **Docket No. 02-0656** |
| **COMMONWEALTH EDISON COMPANY**<br>**Proposed revision of Rider PPO (Power Purchase Option – Market Index), Rate CTC (Customer Transition Charge) and Rider ISS (Interim Supply Service), and to establish Rider CTC-MY (Customer Transition Charge – Multi-Year Experimental)** | ) | **Docket No. 02-0671** |
| **ILLINOIS POWER COMPANY**<br>**Proposed establishment of Rider MVI II, Market Value Index II.** | ) | **Docket No. 02-0672**<br>**(Consolidated)** |

**Direct Panel Testimony of**


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**Constellation NewEnergy, Inc.**

**RODNEY BOYLE**
**MidAmerican Energy Company**

**THOMAS LEIGH**
**AmerenEnergy Marketing**


**ON BEHALF OF THE RES COALITION**

**December 16, 2002**

## I.

## PROFESSIONAL BACKGROUND AND OVERVIEW OF TESTIMONY

**Q. Mr. Bohorquez, please state your name, business affiliation and address, and describe your background.**

A. My name is Mario Bohorquez and I am the Director of Supply Origination and Operations at Constellation NewEnergy, Inc. My business address is 550 W. Washington, Suite 300, Chicago, IL 60661. I have approximately seventeen years of professional experience in wholesale and retail electricity markets, both regulated and competitive. In my current position with Constellation NewEnergy, I am responsible for the following: developing and recommending risk management strategy; originating, negotiating and closing custom wholesale transactions to hedge wholesale to retail risk; optimizing regional wholesale-for-retail book; managing regional risk position to comply with Constellation NewEnergy's risk policy; overseeing execution of transmission service agreements, supply tagging and transmission scheduling; participating in the RTO stakeholders' process and in the Illinois regulatory process assuring viable retail competition in the region; overseeing integrity of customer data inputs to the company's load forecast model and verification of the accuracy of retail load forecast; overseeing settlement of wholesale supply and transmission charges; assessing wholesale opportunities and risks in anticipation of entering new markets; participating in the development of retail products; assisting in the development of regional financial forecast; and participation in the management of the regional enterprise. A copy of my resume is attached hereto and made a part hereof as Attachment A.

**Q. Mr. Boyle, please state your name, business affiliation and address, and describe your background.**

A. My name is Rodney Boyle and I am a Senior Electric Retail Supply Trader with MidAmerican Energy Company ("MidAm"). My business address is 4299 NW Urbandale Drive, Urbandale, Iowa 50322. I have been with MidAmerican Energy Company for 23 years and have served in various positions, including the former Vice President of Energy Products and Services for the Marketing & Sales business unit which operates as a retail electric supplier ("RES") throughout the state of Illinois. As Vice President of Energy Products and Services, my primary duties included responsibility for the profitability of the electric, natural gas, and consumer products and directing the electric and gas product teams which developed and administered pricing products, purchased and managed the supply portfolios, and generally executed the product line strategies within the Marketing & Sales business plan. A copy of my resume is attached hereto and made a part hereof as Attachment B.

**Q. Mr. Leigh, please state your name, business affiliation and address, and describe your background.**

A. My name is Thomas Leigh and I am employed by Ameren Energy Marketing ("AEM") as the Director, Retail Sales. My business address is 400 South Fourth

Street. St. Louis, Missouri 63102. I am responsible for directing the sales and marketing programs to retail customers who are eligible for retail wheeling. Illinois markets have been the primary focus of AEM's marketing efforts on a retail level. My group has direct contact with customers and reviews detailed load and bill histories for several hundred customers each year. My experience at Ameren has encompassed sales and marketing to retail and wholesale customers. When Ameren formed its unregulated marketing affiliate, AEM, in 2000, I assumed my current position to develop and direct the corporation's unregulated retail marketing program. Prior to joining Ameren, I worked for 13 years in the consulting industry, where I focused on energy, environmental and infrastructure projects. A copy of my resume is attached hereto and made a part hereof as Attachment C.

**Q. On whose behalf are you testifying?**

A. We are testifying on behalf of the retail electric supplier coalition or RES Coalition. The RES Coalition is composed of AmerenEnergy Marketing, Blackhawk Energy Services, L.L.C., Central Illinois Light Company, Constellation NewEnergy, Inc., MidAmerican Energy Company, Nicor Energy L.L.C. and Peoples Energy Services Corporation. The RES Coalition has been formed on an *ad hoc* basis to explain to the Commission the current plight of the competitive market, to examine the deficiencies in both the current and proposed market value index ("MVI") methodologies, and to urge the Commission to adopt our recommendations. The solutions proposed by the RES Coalition will foster the development of competition in the Illinois retail electric market.

**Q. What is the purpose of your testimony?**

A. We will present the position of the RES Coalition with respect to certain aspects of the MVI formulas of Commonwealth Edison Company ("ComEd" or "Edison"), Illinois Power Company ("IP" or "Illinois Power"), and Ameren (collectively, the "Utilities") and the proposed revisions filed by each company.

We present numerical evidence that demonstrates that the MVI formulas are broken. Specifically, we will present testimony regarding the following three (3) topics as they relate to each utility:

(1) **Generation capacity**. ComEd's MVI formula needs to recognize the cost of generation capacity and the additional need for the IP and Ameren formulas to be appropriately adjusted regarding these costs;

(2) **Structural flaws in the MVI methodology.** We will discuss the problems associated with calculating forward on-peak and off-peak wrap prices in the MVI methodology and the inadequacies of these calculations in accounting for the basis adjustment between Cinergy and the respective Utilities; and

(3) **Impending RTO Costs**. We will explain the Utilities' failure to address the need to make further adjustments to the MVI methodology once each utility becomes an active member in its respective RTO.

**Q.** **What recommendations or solutions do you propose to correct these three flaws in the MVI methodologies?**

A. **First,** since ComEd's MVI formula does not recognize the cost of **generation capacity,** ComEd's formula should be revised to include an appropriate adjustment. Additionally, the MVI methodologies for IP and Ameren also should be revised to properly capture these costs.

**Second**, the Commission should **adopt, with certain conditions, the proposed use of off-peak wrap forwards and revise the methodology used to calculate the "basis adjustment**" to account for the lack of liquidity in each market. This adjustment will cause the MVI to be more reflective of actual market prices.

**Finally,** we recommend that the **Commission should approve a "placeholder" for PJM/MISO costs**. The Commission should recognize that the MVI methodology will have to be further revised to properly account for the impending market changes and costs resulting from the Utilities joining their respective RTOs.

**Q.** **Do all of your recommendations and proposed solutions apply to each of the Utilities?**

A. The criticism that we have of the MVI methodologies generally apply to each of the three Utilities, but the recommendations and/or the application of the solutions varies among them. The solutions outlined above clearly apply to ComEd, but the

Commission should recognize that (1) Illinois Power's MVI methodology lends itself to the "floating adder" solution, discussed in detail by RES Coalition witnesses Wayne Bollinger, Keith Goerss and Richard Spilky; and (2) Ameren is unlikely to be calculating MVECs any time soon, given the Commission's recent Order conditionally approving the Ameren-CILCO merger in ICC Docket No. 02-0428 which required Ameren to discontinue collecting CTCs until at least May, 2005.

**Q. In the event, that Ameren seeks to reinstate its tariffs for the collection of CTCs, what amendments are necessary to Ameren's tariffs?**

A. First, the overview of the history of the MVI presented by RES Coalition panel witnesses Brent Gale and Dr. Philip R. O'Connor is certainly relevant. If Ameren seeks to reinstate its CTC tariffs in 2005, the Commission will have the benefit of over five (5) years of experience in the Illinois retail electric market upon which it should draw. Second, the specific structural changes that Ameren has proposed to its MVI tariff in this proceeding, including the basis adjustment, should be amended as discussed herein. As discussed in the panel testimony of RES Coalition witnesses Bollinger/Goerss/Spilky, the MVI methodology should be revised to properly account for:

- The cost of energy imbalance risks;
- The cost of odd lot premiums;
- Peak demand coinciding with peak prices;
- Sales and marketing costs; and

- The price of power in the Ameren market when the price on PJM is $0/MWh or less.

Ameren should also amend its MVI filing to allow for the following: (1) quarterly, rather than annual, MVI calculations; (2) February/March snapshots instead of a January snapshot; and (3) the offering of a multi-year CTC for the remainder of the transition period as discussed in the panel testimony of RES Coalition witnesses Bollinger/Goerss/Spilky.

## II.

## THE UTILITIES' MVI FORMULAS DO NOT PROPERLY RECOGNIZE THE COST OF OBTAINING GENERATION CAPACITY

**Q. What is "generation capacity"?**

A. In the context of this proceeding, when we refer to "generation capacity" we are referring to the megawatts of electric power which can be physically delivered by an electric generating unit or system of units.

**Q. What are the current generation capacity requirements of the Utilities?**

A. RESs currently are not required to obtain generation capacity to serve retail customers in the ComEd service territory, but this will likely change soon. Ameren and Illinois Power each require generation capacity with planning reserves in order to reserve network transmission in its respective service territory. Despite ComEd's current business practice, the cost of acquiring generation capacity is a generally recognized cost to serve retail load and is a cost the incumbent utility does not have when RESs serve customers.

**Q. Since ComEd currently does not require RESs to provide generation capacity to serve retail load, is it necessary to recognize the cost of generation capacity in ComEd's MVI tariffs?**

A. Yes. It is necessary because once ComEd becomes fully operational under the PJM RTO, these generation capacity costs will be included in the cost of supplying retail load. Therefore, once ComEd's membership in the PJM RTO commences, ComEd's current OATT policy will terminate in 2003 and the PJM capacity requirements for all load-serving entities will take effect for RESs in the ComEd service territory.

ComEd has already emphasized the importance of such a capacity requirement. In the proceeding in which ComEd petitioned to have service to certain Rate 6L customers declared "competitive" (ICC Docket No. 02-0479), ComEd witness John McCawley testified that "I believe that in its current state of evolution, the electric industry needs a generation capacity obligation such as that in the PJM market." *See* ICC Docket No. 02-0479, ComEd Ex. 2.0 at 8, lines 152-53.

**Q. What is your proposed solution?**

A. As we discuss in greater detail below, ComEd should make a filing with the ICC amending the appropriate tariffs, including Rate CTC and Rider PPO (MI), to properly account for all market changes resulting from the imposition of PJM policies shortly after PJM finalizes its market rules. We recommend that, in anticipation of this market change, the Commission direct ComEd to include a placeholder for such a filing in its revised tariffs.

**Q. Have the Utilities' MVI filings and direct testimony adequately addressed how the future PJM/MISO requirements will be incorporated into capacity requirements?**

A. No. The filings contain no reference to future capacity requirements as a result of transferring control of their transmission systems to either PJM or MISO. In his direct testimony at page 12, lines 249-251, ComEd witness McNeil acknowledges the potential for such necessary changes. However, neither IP nor Ameren address the impact that joining an RTO will have on the calculation of the MVECs. PJM and MISO policies require load serving entities, both RES and utilities, to provide capacity. PJM capacity policies likely will be implemented on December 1, 2003 for ComEd, which is approximately in the middle of the first Period A MVI proposed in ComEd's current filing. Similarly, it is likely that at some point during the transition period, IP will join PJM and Ameren will join MISO. As stated above, the appropriate step at this time is to include a placeholder in the MVI tariffs for PJM/MISO changes that impact the capacity value in the Utilities' MVI filings.

**Q. What other cost (or value of freed-up power and energy) should be addressed relating to ComEd being relieved of obligations once it joins PJM?**

A. Another cost that ComEd presently incurs in serving retail customers is the cost of capacity reserves. ComEd acknowledged the importance of reserves in its petition declaring service to certain Rate 6L customers competitive (ICC Docket No. 02-0479). In that proceeding, ComEd witness McCawley emphasized the benefit of implementing a reserve requirement. (*See* ICC Docket No. 02-0479, ComEd Ex. 2.0 at 7, lines 121-143.) As Mr. McCawley noted, a capacity reserve requirement can provide assurance that adequate generating resources exist to cover load requirements and ensure reliability. To adjust for this cost, ComEd should include a placeholder for the value needed for capacity reserves, which will be set once PJM is the transmission operator.

**Q. Since IP and Ameren each has filed to include a value for generation capacity in its respective MVI formula, is it necessary for them to revise their MVI formulas?**

A. Yes. It is necessary for IP and Ameren each to revise its formula to more accurately reflect the market price for capacity in each respective service area.

**Q. What is an appropriate value for generation capacity in Illinois Power's MVI formula?**

A. The structure of Illinois Power's applicable Riders MVI and PPO and Rate CTC tariffs allow for a unique manner of addressing capacity and energy prices in its service territory. Since under Illinois Power's tariffs an MVI is calculated on a more frequent basis than other utilities, the RES Coalition has proposed an approach specific to Illinois Power, where IP will have a fixed value of $18.00 per kW-year assigned to capacity costs and a specific method of weighting each month of the year. As described in the panel testimony of RES Coalition witnesses Wayne Bollinger, Keith Goerss, and Richard Spilky, this recommendation does not stand alone, but rather is just one component of an entire "floating adder" approach to revising the MVI formula.

**Q. What adjustment would you recommend for Illinois Power if the Commission rejects the "floating adder" approach?**

A. If the Commission rejects the "floating adder" approach for Illinois Power, then the Commission should direct Illinois Power to adopt a tariff-based methodology, similar to the method that has been proposed by Ameren, as discussed below.

**Q. Is it necessary for Ameren to amend its MVI tariffs since it has filed to suspend transition charges?**

A. As discussed by RES Coalition witnesses Mr. Gale and Dr. O'Connor, revisions might not be necessary at this time. However, through the conditions imposed upon Ameren by the Commission in the Ameren – CILCO merger proceeding (ICC Docket No. 02-0428), Ameren is only committed to suspension of the collection of CTCs through May, 2005. If Ameren elects to attempt to reinstate the collection of CTCs after May, 2005, amendments now might better ensure the calculation of MVECs and TCs are accurate.

**Q. In the event that Ameren seeks to reinstate its tariffs for the collection of CTCs, what is an appropriate generation capacity value for Ameren's MVI formula?**

A. As discussed above, we anticipate Ameren will not impose any transition charges going forward and, therefore, will not offer a PPO. However, if Ameren does offer a PPO, we would recommend that the Commission adopt Ameren's tariff-based methodology.

Ameren witness Keith Hock's direct testimony at page 6, lines 119-131, addressed the utility's preferred method of setting an appropriate capacity value. For the Ameren service territory, we agree with Ameren's preferred approach to establish generation capacity value through a tariff-based methodology. We anticipate that MISO will establish capacity and energy markets for prospective buyers and sellers in the future, but an implementation date has not been confirmed. Since Ameren is operating in Illinois as an integrated distribution company and cannot market capacity or energy, we recommend that prior to MISO's implementation, Ameren act as an independent facilitator of capacity auctions for serving retail load in its service area. The capacity requirements would be specified by Ameren in accordance with the principles and procedures of the applicable OATT. Each period Ameren calculates an MVI, the company shall also conduct a capacity auction in which prospective buyers/sellers submit bids or offers indicating the amounts (MW) and prices ($/MW) they are willing to transact for capacity to serve retail load in the Ameren service area. Ameren would post the results to allow buyers and sellers to complete bilateral agreements as appropriate. Ameren would use the bid/offer data to establish a generation capacity value that would be added to the MVECs for the applicable MVI period.

## III.

## THE COMMISSION SHOULD REQUIRE THE UTILITIES TO MAKE THEIR ESTIMATES OF FORWARD OFF-PEAK WRAP PRICES AND BASIS ADJUSTMENTS FOR BOTH ON-PEAK AND OFF-PEAK PRICES MORE ACCURATE

**Q. Have you identified ways in which the Utilities' MVI methodology should be restructured to yield more accurate MVECs?**

A. Yes. We will present testimony recommending that the Commission require the Utilities to make revisions to their methodologies to yield more accurate off-peak and forward-wrap prices and a more accurate basis adjustment. As discussed fully in the panel testimony of RES Coalition witnesses Wayne Bollinger, Keith Goerss, and Richard Spilky, these specific adjustments may not be necessary for IP, if the Commission adopts the RES Coalition's proposed "floating adder" approach. However, if the Commission fails to adopt such an approach, these revisions should be applied to IP as well as ComEd and Ameren.

**Q. What are "off-peak" prices and how are they calculated in the Utilities' existing MVI methodologies?**

A. Off-peak prices are market prices generally for the hours between 10:00 p.m. and 6:00 a.m. during the weekdays, all day on holidays and weekends, when demand is generally at its lowest.

Existing MVI methodologies use historical prices for the off-peak period as proxies for the off-peak forward prices, and do not utilize any basis adjustment for off-peak prices. Also, the current MVI methodologies employ historical Utility weekday off-peak spot market prices, and the historical relationship between weekday off-peak prices and weekend prices in PJM West to calculate weekend prices. All three Utilities have proposed revisions to address the issue that market prices, including off-peak prices, do not match the location of the load or the time period of the market values.

**Q. What revisions have the Utilities proposed to the way in which "off-peak" prices are calculated in their MVI methodologies?**

A. The Utilities have proposed the following change regarding the use of historical off-peak prices. Each Utility will now use "Into Cinergy" off-peak forward wrap prices with a basis adjustment to determine values during both the on-peak and off-peak periods. While this is an improvement in that the use of forwards is more appropriate for forward-looking off-peak market expectations, the Utilities improvements still do not go far enough in providing a more accurate MVI methodology as discussed below.

**Q. What are "forward-wrap" prices and how are they calculated in the Utilities' existing MVI methodologies?**

A. Forward-wrap prices represent the market prices for wholesale energy delivered during future off-peak hours of a customer's energy profile. The forward wrap as defined by the wholesale energy market includes weekday hours between 10:00 p.m. and 6:00 a.m., typically referred to as the 5x8, and all weekend hours, typically referred to as the 2x24. The Utilities' existing MVI methodologies only consider historical off-peak prices, which do not reflect the risk premium embedded in future price commitments. Although the Utilities have proposed to use forward prices for off-peak wrap prices, the Utilities' proposal fails to accurately reflect the illiquidity of these markets.

### A. THE COMMISSION SHOULD REQUIRE THE UTILITIES TO MONITOR THE AVAILABILITY OF FORWARD PRICES AND REQUIRE THE UTILITIES TO TAKE CORRECTIVE ACTIONS, IF NECESSARY

**Q. Do the Utilities' proposed methodologies for estimating forward off-peak wrap prices represent an improvement over the current methodology?**

A. Yes. The proposed methodologies for determining the value of off-peak wrap prices are an improvement over current methodologies. Setting aside certain issues described below, the revised methodologies would yield prices that are a better representation of forward looking expectations for market prices.

**Q. What is problematic about the Utilities' proposed methodologies for estimating forward off-peak wrap prices?**

A. Forward off-peak products are not traded as vigorously as peak products and the resulting limited availability of forward off-peak wrap prices makes an accurate estimation of these prices challenging. This trading characteristic is true of the Utilities' markets as well as the markets which provide the source of estimated market prices in the MVI methodology.

This problem would be further exacerbated if the Commission were to accept the proposal of ComEd and Ameren to move the snapshot period to January, since even fewer market price data points exist for this time period.

**Q. What evidence exists that forward off-peak products are not traded as vigorously as peak products?**

A. Evidence of the lack of forward off-peak wrap prices can be found in ComEd's response to ICC Staff Data Request 1.01, in attachment 1.01(d). For the current snapshot period (data polled February 25, 2002 through March 22, 2002), ComEd reported only 15 observances of actual trades for a period extending forward more than 4.5 years (June 2002 through December 2006). For the proposed snapshot period (data polled January 2, 2002 through January 29, 2002), ComEd reported no trade information for a period extending forward more than 4.5 years (June 2002 through December 2006). This missing data undermines the assertion that under their proposals the Utilities' could obtain an accurate representation of forward off-peak prices.

**Q. How should the unavailability of data for forward off-peak wrap prices be resolved?**

A. As part of its Final Order in this case, the Commission should require the Utilities to monitor and report the availability of forward off-peak wrap price data. The Utilities should be required to keep continuous valuations of off-peak wrap prices similar to the ones they keep for on-peak price data. These prices should be updated during the data collection periods. In the event that forward off-peak wrap price data is insufficient to adequately estimate forward prices, the Commission should then require the Utilities to implement an alternative methodology. This methodology could be based on prices resulting from a competitive auction of forward off-peak wrap products delivered in the Utilities' service territories. The resulting prices would then be used to calculate forward prices.

**Q. Should the Commission require the Utilities to monitor and report the availability of forward on-peak price data and implement an alternative methodology in the event that forward on-peak price data is inadequate?**

A. Yes. With the impending implementation of their respective RTOs, it is possible that the availability of on-peak forward price data may become insufficient to adequately estimate forward on-peak prices. In the event that the availability of forward on-peak prices become insufficient to adequately estimate forward on-peak prices, the Commission should require the Utilities to implement an alternative methodology. This methodology could be based on prices resulting from a competitive auction of forward on-peak products delivered in the Utilities' service territories. The resulting prices would then be used to calculate forward prices.

**Q. Have other features of the methodology for determining forward prices been inadequately addressed by the Utilities?**

A. Yes. The Utilities' proposed basis adjustment also needs to be modified because, as it currently stands, the adjustment ignores liquidity risk. By ignoring this risk, the MVI fails to account for a significant cost element of doing business in the Utilities' markets.

### B. THE COMMISSION SHOULD REQUIRE THE UTILITIES TO MAKE REVISIONS TO ITS "BASIS ADJUSTMENT" METHODOLOGY

**Q. What is the "basis adjustment" and how is it calculated in the Utilities' existing MVI methodologies?**

A. The term "basis" represents the locational or geographic differences in prices of the same product from one location to another. A "basis adjustment" adjusts for price differences attributable to location. Currently, the Utilities' basis adjustments are determined from transaction data as the average of the daily ratio of one region or Into Hub energy price to another region or Into Hub energy price. The basis adjustment in each utility's MVI filing considers only the price ratio of day-ahead products and assumes buyers or sellers of forward products in each utility's territory pay the midpoint of the bid-ask quotes.

**Q. Do the Utilities' proposed basis adjustments yield the true price of forward products in their service territories?**

A. No. The basis adjustments proposed by the Utilities fail to account for the liquidity risk found in the forward markets. The proposed basis adjustment in each utility's MVI filing considers only the price ratio of relatively liquid, day-ahead products and, in so doing, erroneously assumes the Utilities forward markets are as liquid as the Cinergy markets. As would most likely be the case when transacting in a liquid market such as Cinergy, the proposed adjustment assumes buyers or sellers of forward products in each utility's territory pay the midpoint of the bid-ask quotes. However, in illiquid markets, such as those in which the utilities operate, the expected price for a forward product is more likely to settle close to the ask (higher) quote if a buyer initiates the transaction. Conversely, if the seller initiates the transaction it is more likely that the transaction price will settle close to the bid (lower) quote. This uncertainty in the price of a product translates to liquidity risk.

**Q. Is the forward Cinergy market more liquid than the ComEd, Illinois Power and Ameren forward markets?**

A. Yes. The Cinergy forward market is significantly more liquid than the ComEd, IP and Ameren forward markets. Because of the relative illiquidity of these markets (for both peak and off-peak products), Into Cinergy forward market prices are currently being used in the MVI calculation. This substitution makes the use of a basis adjustment between these Utilities and Cinergy necessary.

**Q. How can you assess the liquidity risk in a market?**

A. One way to assess the liquidity risk in a market is to calculate the numerical difference between the bid and ask quotes. This measurement is called the bid-ask spread. A wider bid-ask spread indicates greater liquidity risk.

**Q. To demonstrate this illiquidity, how do the bid-ask spreads compare in the Cinergy and ComEd markets?**

A. The bid-ask price spread found in an illiquid market for a given product is much wider than the bid-ask spread found in a more liquid market for the same product. For instance, on Monday, September 9, 2002, the InterContinental Exchange ("ICE") reported a $0.75/MWh bid-ask spread for Jan 03 - Feb 03 peak power delivered Into Cinergy. For the same product delivered into ComEd's service territory, ICE reported $1.65/MWh spread. This example highlights the greater liquidity risk in ComEd over Cinergy, since the reported spread for the ComEd market was more than double. The table below gives further evidence of the disparity in bid-ask spreads in ComEd as compared with Cinergy. The spreads would be even greater in the Ameren and IP markets because these markets are even less liquid than ComEd.

| Bid-Ask Spreads Observed in the Cinergy and ComEd Markets<br>Note: Wider bid-ask spreads and deviations indicate greater liquidity risk.<br>Data Sources: Enron Online, ICE, and Prebon | | | | | |
|---|---|---|---|---|---|
| | | Average Spread | | Standard Deviation | |
| Peak Product | Observation Period | Cinergy | ComEd | Cinergy | ComEd |
| Winter 2003 | Aug 01 – Jul 02 | 0.56 | 1.69 | 0.32 | 0.83 |
| Summer 2003 | Sep 01 – Jul 02 | 0.81 | 2.61 | 0.46 | 1.10 |
| Cal 2003 | Apr 01 – Mar 02 | 0.88 | 1.75 | 0.37 | 0.66 |

**Q. Are suppliers of competitive retail load exposed to liquidity risk in all three service territories?**

A. Yes. Utilities and RESs purchasing electric power and energy to serve retail load (RCDS customers, which includes PPO and ISS customers) are exposed to this risk. Due to the illiquidity present in these markets, suppliers purchasing forward products will most likely pay a price closer to the ask (higher) quote rather than the midpoint. Since these suppliers are often paying closer to the ask quote, the MVI underestimates the price these buyers are paying (the true forward price). This true price needs to be reflected in the MVI calculation.

**Q. Do the shortcomings mentioned above apply to both the on-peak and off-peak basis adjustments?**

A. Yes. The Utilities apply the same basis adjustment to both on-peak and off-peak prices and, therefore, each must be appropriately adjusted.

**Q. How could the basis adjustment take this illiquidity into account?**

A. The MVI calculation would be more accurate if the MVI methodology, as proposed by the Utilities were modified to include an adder compensating for the liquidity risk found in the forward markets of each utility. Based on the historical evidence of the bid-ask spread shown in the ComEd example for the Cal 03 calendar product, an appropriate adder would be $0.88/MWh (half of the bid-ask spread). Given that ComEd, IP, and Ameren forward price data is scarce, the liquidity risk premium alternatively could be calculated using the **full** bid-ask spread found in the Cinergy market for forward products extending 12 months into the future (Cal product). As shown above, this alternative liquidity risk premium calculation (full bid-ask spread for Cinergy Cal product) would also yield a $0.88/MWh adder. This adder should be calculated during each snapshot period, based on the average of the most recent 12 months' bid-ask spreads found in Cinergy forward products, extending 12 months into the future.

## IV.

## THE COMMISSION SHOULD REQUIRE THE UTILITIES TO REVISE THEIR MVI TARIFFS TO RECOGNIZE THE ADDITIONAL COSTS AND MARKET CHANGES THAT WILL RESULT FROM EACH UTILITY'S IMPENDING MEMBERSHIP IN AN RTO

**Q. What are some of the market changes that can be expected as a consequence of ComEd and IP joining PJM and Ameren joining MISO?**

A. It is difficult to fully assess the effect on each utility when it joins a fully operational RTO. However, we have compiled a partial list of potential market changes:

- Transmission rates may change;
- PJM may impose a capacity requirement on Load Serving Entities;
- Character of Firm Transmission Service would change within PJM and MISO;
- Potential transmission congestion may require new hedging strategies and products not currently in existence;
- The ComEd Hub may cease to exist;
- MISO may impose different capacity requirements than Ameren currently has;
- Firm LD Seller's Choice contracts would no longer be useful to serve retail load if they no longer hedge delivery risk adequately;
- Forward price quotes based on Firm LD contracts delivered into the Cinergy service territory may not be adequate proxies for power prices delivered into the ComEd service territory; and
- Imbalance settlements would most likely be changed.

**Q. What are some potential cost drivers that could reasonably be expected as a consequence of market changes under PJM and MISO?**

A. Neither RTO has finalized its rules for operation within each utility's service territory which makes it difficult to properly assess the cost drivers associated with their current rules. However, it is a reasonable prediction that, among other things, full implementation of the PJM and MISO markets will cause incremental costs such as the cost of compliance with RTO capacity requirements, residual congestion costs associated with a deficient allocation of firm transmission rights, and the cost associated with altered flow patterns on the transmission grid.

**Q. Do the Utilities' proposed MVI calculations adequately account for the expected costs brought about by the Utilities joining fully operational RTOs?**

A. No. As discussed above, the MVI calculations do not adequately account for potential costs resulting from market changes caused by RTOs.

**Q. Should these potential costs be incorporated in the MVI calculation?**

A. Yes. Since incurring these potential costs would be necessary to serve retail load, they should be eventually included in the MVI calculation.

**Q. Where other potential costs associated with the impending market changes could be incorporated for ComEd?**

A. Some of these potential costs, such as changes in transmission rates, need to be incorporated into ComEd's Rider TS because Rider TS, along with the MVI, determines the value of each RCDS customer's CTC.

**Q. Does the current language in Rider TS adequately account for these expected costs?**

A. No. Rider TS does not adequately account for expected or unexpected market changes. In fact, the language in Rider TS does not describe how ComEd will calculate and allocate PJM related costs such as congestion management costs. Furthermore, Rider TS is silent about other potential costs such as the cost of PJM imposed capacity. As it presently exists, Rider TS may not be used as a vehicle to adequately capture all PJM-related costs. It is important to properly account for all costs associated with ComEd joining PJM because these costs have the potential to affect the value of CTCs imposed on RCDS customers.

**Q. What should the Commission do to require the Utilities to account for the impending market changes resulting from the impending RTO implementation?**

A. As recommended above, the Commission should require the Utilities to incorporate a placeholder for these costs into the MVI tariffs and, after RTO market rules are finalized, make a filing with the Commission amending all of their tariffs to properly account for all market changes resulting from the RTO implementation. At page 12, lines 249-251 of his testimony, ComEd witness McNeil, appears to support this position.

**Q. If the above changes are made to the Companies' MVI formulas, do you believe that the competitive retail electric markets will improve?**

A. Yes.

## V.

## RECOMMENDED SOLUTIONS

**Q. In summary, what are the solutions that the RES Coalition proposes to solve the problems that you have identified with the Utilities' existing and proposed MVI methodologies?**

A. The RES Coalition recommends that the Commission enter a Final Order that directs the Utilities to make the following revisions:

(1) IP and Ameren should be directed to modify their MVI formulas to more accurately reflect generation capacity costs.

(2) ComEd should be directed to modify its MVI tariffs to include a placeholder related to RTO-imposed generation capacity costs, recognizing that its methodology will be revised once an RTO establishes requirements for entities that provide retail service in the ComEd service area.

(3) The Commission should require the Utilities to monitor and report the availability of forward price data (both on-peak and off-peak). If the Commission determines that such data is insufficient, the Commission should require the Utilities to estimate these prices using a competitive auction of forward products.

(4) The Commission should include an "adder" to the basis adjustment in the MVI formulas to account for the liquidity risk that is present in each market.

(5) The Commission should require the Utilities to agree to make a filing amending the MVI formulas once they join RTOs, to account for the resulting market changes.

**Q. Does this conclude your testimony?**

A. Yes.